ATTACHMENT 2

History of Shared-Savings Incentive Mechanisms For Energy Efficiency Programs

The concept of providing utilities with an opportunity to earn from their demand-side management (DSM)[1] efforts was developed in the late 1980s in response to the Commission's stated need to take a fresh look at the role of DSM in utility resource procurement. Pursuant to Decision (D.) 89-05-067, the Commission convened an en banc hearing on July 20, 1989 to address the central questions of how DSM programs should fit into utility resource procurement, and how regulation could encourage desirable investments in demand-side resources. Several participants recommended that utilities be given the opportunity to earn on DSM activities. At the end of the en banc, the Commission directed interested parties to collaborate on a blueprint for the revitalization of DSM activity in California.

A. The California Collaborative

The California Collaborative working group (Collaborative) set its own agenda and membership. Its stakeholders were a wide array of interested groups: California's four major investor-owned energy utilities, representatives of various California state agencies, environmentalists, residential, commercial, industrial and low-income ratepayers, agriculture, energy service companies and independent energy producers. The Collaborative observers included legislative representatives, the South Coast Air Quality Management District and several energy consulting firms. The Commission's Strategic Planning Division also assisted the Collaborative.

In January 1990, the Collaborative presented a report to the Commission entitled An Energy Efficiency Blueprint for California (the Blueprint). In that document, the Collaborative stakeholders proposed new regulatory mechanisms (referred to as "shareholder incentive" or "earnings" mechanisms) to allow utility shareholders to participate in the benefits of DSM. They also created new and expanded DSM programs, and identified key characteristics of DSM programs which must be considered in order to

[1] DSM programs focus on the customer side of the utility meter and have included programs for load management and energy efficiency, among others.

provide lasting energy efficiency savings. Finally, they recommended policies to govern the regulatory treatment of utility DSM programs.

B. Adoption of Experimental DSM Shareholder Incentives

As promised in the Blueprint, the utilities filed applications requesting Commission authorization for expanded DSM programs and shareholder incentive mechanisms. Although the details of the mechanisms varied across utilities, each utility proposed some form of shared-savings or rate of return approach for programs designed to cost-effectively reduce the need for supply-side additions. They also proposed a fixed management fee approach for programs that primarily addressed equity concerns (and were not cost-effective or cost-effectiveness was difficult to measure), such as low-income energy efficiency (LIEE). [2]

The parties to the proceeding subsequently entered into settlement agreements, and in D.90-08-068 and D.90-12-071, the Commission approved the terms of the respective settlements, with some minor modifications. Pursuant to the settlement agreements, each utility convened Advisory Committees to assist them in the implementation of the approved programs. The settlement agreements also contained measurement and evaluation plans to be completed as condition for the continuation of shareholder incentives. However, the methods and protocols for measuring per unit savings from DSM were still in their early development stages. As a result, these initial shared-savings mechanisms did not require that forecasted per unit savings be adjusted "ex post" by the results of measurement studies conducted after program implementation. For each program year, utilities were authorized all of their earnings one year after program implementation, based on verified program costs and program participation. Per unit savings were based on "ex ante" estimates, that is, prespecified savings based primarily on engineering studies. The utilities were required to conduct ex post studies to

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[2] Since the focus of this discussion is on the shared-savings mechanisms for energy efficiency programs, we do not recount the development of the "management fee" incentive mechanism for LIEE in any further detail in this document. We use the term "energy efficiency programs" throughout this decision to refer exclusively to *non-LIEE* energy efficiency services. For background on the LIEE incentive mechanism, see D.94-10-059, D.95-12-054, D.96-12-079 and D.00-09-038.

measure post-installation per unit savings—but only for the purpose of updating DSM savings estimates on a prospective basis.

The shareholder incentive mechanisms adopted in D.90-08-068 and D.90-12-071 were experimental, and were authorized through 1991 for SCE and SDG&E and through 1992 for PG&E and SoCal. [3] In approving the experiments, the Commission identified the need for an Order Instituting Rulemaking (OIR) to provide a forum for "comparing the different DSM models…and to assess the relative success of the different approaches." [4] The commission intended the OIR to lead to "the development of statewide standards and benchmarks by which to measure energy efficiency and to measure the appropriate levels of incentives." [5] To assist in this evaluation, the Commission directed the Commission Advisory and Compliance Division (CACD) to submit a report on the effectiveness of the adopted incentive mechanisms. [6]

C. The DSM OIR and Evaluation of Experimental DSM Incentive Mechanisms

The issuance of the DSM OIR and companion Investigation (Rulemaking (R.) 91-08-003/Investigation (I.) 91-08-002) took up where the Collaborative left off. On January 8, 1993, CACD's report on shareholder incentives, Evaluation of DSM Shareholder Incentive Mechanisms prepared by Wisconsin Energy Conservation Corporation (WECC), was filed and served on all parties to R.91-08-003/I.91-08-002. The Commission held an informal full panel hearing on February 25, 1993 to assess accomplishments in DSM since the Collaborative and to identify the key issues for the future.

The proceeding was bifurcated into two phases. The first phase examined threshold issues related to shareholder incentives, including whether they should be

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[3] The mechanisms were subsequently extended (and in some cases modified) in intervening general rate cases and other proceedings prior to the Commission's overall evaluation of the experimental mechanisms in D.93-09-078.

[4] D.90-08-068; 37 CPUC 2d, 347 at 368.

[5] *Id.* See also D.92-02-075 (43 CPUC 2d, 316).

[6] "CACD" stands for the Commission's Advisory and Compliance Division, which is now identified as individual industry Divisions, e.g., Energy Division.

continued on a longer term basis. Five days of evidentiary hearings were held on the threshold issues. Following the submittal of briefs, the Commission issued D.93-09-078 on September 17, 1993. In that decision, the Commission concluded that shareholder incentives should be continued:

> "Our experiment in shareholder incentives was initiated within the broader context of California policies to promote least-cost energy resource planning and procurement. To that end, both this Commission and the California Legislature have encouraged energy utilities to exploit all practicable and cost-effective energy efficiency improvements that are not being exploited by other market entities. (See PU Code §701.1(b).) [footnote omitted] [7]
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> "…[T]he record in this proceeding convinces us that shareholder incentives, while not the only factor contributing to DSM accomplishments over the experimental period, certainly played a significant role. We are also persuaded by the testimony in this proceeding that regulatory and financial biases against DSM still exist under our regulatory framework. These include the fact that utilities only earn on supply-side investments under current regulatory practices absent DSM incentives, and that DSM investments will increase rates in the short run, even though they are intended to minimize revenue requirements and customer bills over time. These biases make DSM less attractive to the utility than other resource options, even when DSM is least-cost from a ratepayer or societal perspective." [8]
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> "Today we find that these incentives have contributed to the utilities' revitalized interest in pursuing cost-effective DSM in a manner that yields significant net benefits to all ratepayers. We determine that DSM shareholder incentives should be continued under our current regulatory framework. As described in today's order, shareholder incentives are not without risks; however, we believe that those risks are manageable with prudent planning and regulatory oversight. We will monitor the benefits, costs and risks associated with DSM shareholder incentives to ensure that they continue to produce significant ratepayer benefits over time."[9]

[7] D.93-09-078, 51 CPUC 2d, 371 at 380.

[8] *Ibid.* at 382

[9] *Ibid.* at 373.

At the same time, the Commission recognized that it was exploring reforms in both the gas and electric industries in other proceedings that could affect its conclusions about DSM shareholder incentives.[10] Accordingly, the Commission limited the conclusions reached in this decision to "present circumstances", noting that it may need to reevaluate DSM shareholder incentives as a regulatory tool should those proceedings result in regulatory changes. [11] In addition, the Commission established an implementation phase to reexamine all aspects of the level and design of previously tested incentive mechanisms, noting that the endorsement of shareholder incentives for DSM in principle did not extend to those specifics.[12]

D. Adoption of Ex Post Measurement Protocols and DSM OIR Implementation Phase

By 1993, ex post measurement had reached a stage where specific protocols could be adopted. The implementation phase of the DSM OIR represented the first opportunity to integrate the ex post measurement protocols into the earnings and penalty calculations associated with existing (and future) shareholder incentive mechanisms. In D.93-05-063, the Commission established ex post measurement and evaluation (M&E) protocols for measuring per unit savings after program implementation, both in terms of the first-year load impacts and the persistence of those impacts over time. More specifically, the adopted M&E protocols required utilities to conduct load impact studies the year after program installation. The protocols also called for a one-time technical performance study (which developed technical degradation factors) in the third or fourth year, depending on the program. In addition, the utilities were required to conduct two

[10] On December 16, 1992, the Commission issued a rulemaking/investigation proceeding on gas regulatory reform (I.91-12-017/R.91-12-016) and on July 15, 1993, the Commission requested comments on reform of electric services industry and regulatory structure. *Ibid.* footnote 2.

[11] *Ibid.* at 373.

[12] *Id.*

retention studies in either the third and sixth or fourth and ninth year (depending on the program) to verify the useful lives of energy efficiency measures after installation. [13]

In that decision, the Commission also established an earnings payment schedule that directly linked to the results of ex post measurement studies. Beginning in 1994, for all existing energy efficiency incentive mechanisms, earnings would be paid out over a 10-year period (in four installments), rather than the current one-year payout period. Each installment would be dependent on specific results designed to true-up the real benefits: actual measures installed and costs for the first installment, load impact studies for the second installment, technical degradation and retention studies for the third installment, and retention studies for the fourth installment. In considering the various proposals presented in the case for earnings recovery, the Commission stated:

> "Balancing the alternatives for earnings recovery before us forces us to weigh the need to provide utilities with an incentive to complete evaluations and to maintain utility commitment. But, most importantly, we must also weigh the utilities' accountability to ratepayers for claimed energy savings…
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> …Linking earnings recovery to a single persistence study over the measure life does not adequately ensure that utilities will remain committed to their M&E efforts beyond the first few years. That, in turn, could compromise our goal that DSM savings estimates will become more reliable over time…
>
> …At the same time, we are aware that utility commitment to DSM is an important factor. We have struggled with utility commitment to these programs since DSM incentives began. We also struggle with ensuring that we send the correct signals so that utilities and parties remain enthusiastic through our many decisions about DSM funding and incentive mechanisms. The Commission has labored to gain this utility commitment, and thus far it has been a primary focus…We are more persuaded by the concept of tying earnings to additional persistence studies over a longer measurement period, rather than relying, for purposes of this interim program, on non-financial incentives to motivate utilities to complete M&E studies expeditiously."[14]

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[13] 49 CPUC 2d, 327. The ex post measurement requirements apply to most measures installed under the program; however, certain lower-impact measures are exempt from some or all of these requirements.

[14] 49 CPUC 2d, 327 at 351-352.

As the measurement and pay out protocols were being developed, the Commission also turned to the task of designing of the next generation of DSM incentive mechanisms. Ten days of workshops and fifteen days of evidentiary hearings were held on this topic. All the parties to the proceeding reached consensus that the new generation of shareholder incentives for energy efficiency programs should take the form of a shared-savings mechanism, versus the "rate of return" approach implemented under some of the earlier experimental mechanisms. However, as discussed extensively in D.94-10-059, the parties disagreed significantly on the design of that shared-savings mechanism. Most of the testimony focused on what the appropriate earnings level and associated performance earnings rates should be, i.e., the overall level of earnings opportunity for shareholders under the mechanism.

In considering the issues associated with the design of shareholder incentives, the Commission first established certain basic policy principles, as discussed below:

> "…[W]e believe that least-cost procurement is best achieved by motivating utilities to maximize DSM benefits whenever and wherever those opportunities actually exist in the market. Once a minimum level of performance has been met, we believe the utilities should be able to increase earnings if and only if they increase net benefits (savings minus costs) to ratepayers, and should receive less earnings for reduced benefits. We also believe that the relationship between earnings and net benefits should be proportional, e.g., a 10% increase (decrease) in net benefits should increase (decrease) earnings by 10%. In addition, the rates at which utilities earn (or are penalized) should be the same across programs or portfolios and across utilities.
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> "Utilities should be accountable not only for achieving net benefits, but also for guaranteeing the cost-effectiveness of DSM activities. Ratepayers should not continue financing DSM investments without adequate protection against the potential losses associated with performance risk. With the adoption of our ex post measurement protocols, we now have the means of providing such protection. Accordingly, we expect utilities to compensate ratepayers for 100% of losses (i.e., negative net benefits), up to the total amount of DSM program costs recovered in rates." [15]

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[15] D.94-10-059, 57 CPUC 2d, 1 at 13.

Based on these principles and the adopted ex post measurement protocols, the Commission adopted the following shared-savings mechanism beginning in 1995:

- Ratepayers invest in energy efficiency programs by funding the programs through rates. The "return" on the investment is the net benefits (energy savings less costs) achieved by the programs. This return does not reflect the shareholder earnings paid out under the shared-savings mechanism.

- Ratepayers and utilities share any positive return (net benefits) at a shared-savings rate that is constant across utilities and programs, once a minimum performance threshold is achieved. The sharing formula and minimum performance requirements are applied to two separate portfolios: one for residential and one for nonresidential programs.

- Utilities compensate ratepayers for 100% of any losses (negative net benefits) up to the total amount of program costs recovered in rates, on a portfolio basis.

- All energy savings are verified after-the-fact through ex post measurement studies that are filed and litigated before the Commission in AEAPs. The measurement studies are conducted according to the ex post Measurement and Evaluation (M&E) Protocols adopted by Commission. Appendix 3 describes the role of M&E studies in the earnings pay-out under the mechanism.

- Net benefits for earnings claims purposes are adjusted to reflect the aggregate measurement and evaluation costs associated with each program year.

- The payout of utility shareholder incentives occurs over four earnings claims, which extend over a 7-10 year period after measure installation. Each installment represents 25% of the total earnings associated with the program.

- Before any shareholder earnings can accrue, the utility must achieve 75% of forecasted performance for each portfolio, as verified in the first earnings claim. That threshold is referred to as the "minimum performance standard" or "MPS". Once the utilities have met the MPS, then earnings for each portfolio are calculated at the shared-savings rate.

- The first earnings claim is subject to verification of the program costs and actual number of participants in the program (measures installed), relative to the number projected in initial savings estimates.

- The second earnings claim is subject to *ex post* verification of the *ex ante* savings per measure assumed in the initial savings projections.

- The third and fourth earnings claims are subject to verification of the persistence/retention of energy savings over time, e.g., by assessing equipment degradation or removal.

The Commission next considered the appropriateness of using the utilities' authorized rate of return as the starting point for a shared savings rate, but rejected that approach for the following reasons:

> "As DRA and others point out, using the authorized rate of return as the shared-savings rate does not reflect what the utility actually earns on utility-constructed plants. (RT at 5211, Exh. 341, pp. 24-26.) Under cost-of-service ratemaking, earnings accrue on the unamortized portion of rate base throughout the useful life of the plant. Applying the authorized rate of return to DSM net benefits assumes a one-year amortization.
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> "A simple example illustrates how this approach underestimates the total earnings stream from a rate-based plant. Suppose $100 million in plant costs is rate based at an authorized rate of return of 10%. However, assuming a 10-year plant life and straight-line depreciation, earnings on that rate-based facility would actually be $54. Rate base would decrease by $10 per year (in depreciation), and the 10% rate would be applied to each year-end balance. [footnote omitted.] Hence, the effective earnings rate on a $100 million plant investment would be 54%, as compared to the 10% authorized rate of return." [16]

Parties to the proceeding presented a range of 26% to 52% for the effective earnings rate associated with supply-side resources deferred or avoided by DSM investments. This represented target earnings[17] in the range of $77 million to $153 million for a single program year on a statewide basis. Noting that DSM programs must, by definition, produce higher resource benefits per equivalent costs than the supply-side alternative it replaces, the Commission concluded that the starting point for comparable

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[16] D.91-10-059; 57 CPUC 2d, 1 at 52. "DRA" stands for Division of Ratepayer Advocates, which was subsequently renamed the Office of Ratepayer Advocates (ORA).

[17] These target earnings were based on estimates on the record of the net benefits associated with PY1994 program activity.

earnings would be even higher if earnings rates were based on equivalent performance, rather than costs:

> "Had this type of earnings comparison been made in the past, we would have seen very clearly that previous DSM mechanisms offered significantly lower earnings opportunity for DSM than for supply-side alternatives. For example, PG&E found that DSM investments provided earnings of 0.26 to 0.29 cents/kWh in comparison to $1.10 to $1.29 cents/kWh on the supply side over the 1990-1992 period. [] This comparison considered earnings from the full portfolio of PG&E's supply-side resources, including rate based plant, purchased power and transmission and distribution facilities. [18]
>
> "The comparisons presented above are not intended to imply that historical incentive levels were too low or unfair to shareholders. As discussed in this decision, our experimental DSM incentive mechanisms relied exclusively on ex ante assumptions of per-unit load impacts and savings persistence, and placed almost all performance risks on ratepayers. Hence, it was appropriate to establish earnings targets that reflected this relatively low risk to shareholders. However, these comparisons are useful in establishing what the appropriate starting point should be for today's consideration of relative risks and rewards." [19]

The Commission then went on to consider how best to compare the earnings opportunity from DSM and supply-side resources in the context of their different (and changing) risk/reward provides. In addition to who funds the initial investment, the Commission identified other dimensions to relative risk that it needed to consider, including how shareholder earnings vary with project performance and who bears the risk of non cost-effective investments. Appendix 1 presents the Commission's discussion of these dimensions of risk as they related to the ratemaking treatment for supply-side resources at the time and the DSM shareholder incentive mechanism discussed above. Based on this discussion, the Commission adopted a target earnings (shared savings) rate of 30%. This translates to $89 million in earnings, or 30% of the $295 million in net

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[18] *Id.*

[19] *Ibid.,* at 54.

benefits produced by these programs if actual is equal to target performance, based on 1994 program estimates:

> "At this rate, the utility will receive an opportunity to earn that is significantly higher than current earnings rates, reflecting our observations that the performance risks associated with DSM have been substantially shifted from ratepayers to shareholders. This rate and corresponding target earnings level are also within the range of earnings opportunity afforded to comparable supply-side investments, consistent with our own rules and the standards presented in the Energy Policy Act of 1992. [footnote omitted.] We choose an earnings rate at the lower end of this range to balance the significant risk-mitigating effects that portfolio diversification will have on shareholder exposure. At this rate, target earnings on a statewide basis are estimated at approximately $89 million, based on 1994 program year activities. The potential downside to the utilities is the full $215 million in estimated program costs. Should the utilities exceed their performance targets, they would continue to share net benefits with ratepayers at a 30% rate."[20]

In summarizing its decision, the Commission presented Table 1 below. This table presents the statewide and utility-specific estimates of earnings and penalties under the adopted mechanism at different levels of performance, based on estimates of PY1994 program activity.

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[20] *Ibid*. at 58.

TABLE 1

EARNINGS AND PENALTY ESTIMATES
AT DIFFERENT LEVELS OF PERFORMANCE
($ millions, pre-tax)

Based on Adopted Shared-Savings Mechanism
Applied to PY1994 Program Activities

Recorded Performance (% of Forecast)	PG&E	SCE	SDG&E	SoCal	Statewide Total
200%	97	47	19	14	177
150%	73	35	15	10	133
100%	49	23	10	7	89
50%	0	0	0	0	0
30%	0	0	0	0	0
-30%	-49	-23	-10	-7	-89
-50%	-81	-39	-16	-12	-148
-90%	-119	-51	-25	-20	-215
-150%	-119	-51	-25	-20	-215
Forecasted Performance Earnings Basis	162	78	32	23	295
Forecasted Net Benefits Based on TRC	137	73	29	23	262

As indicated above, the Commission's best estimate at the time was that the utilities could earn $89 million (collectively) for a typical program year if they met their savings targets, with payments spread over the 7 to10-year measurement period. The

Commission estimated that those savings targets would yield $262 to $295 million in net benefits on a statewide basis. [21] At 200% of target savings, the Commission estimated that earnings could be as high as $177 million under the incentive mechanism. If energy efficiency activities were not cost-effective, the penalties could be as large as $215 million, or the total ratepayer cost of the programs.

The Commission also anticipated that the adopted incentive mechanisms and M&E protocols would be reevaluated on a prospective basis, based on experience with the mechanisms and CACD's evaluation of associated ratepayer risks, costs and benefits. The Commission anticipated that such a review would be conducted in 1997, during the 1997 AEAP or other procedural forum identified by the Commission. In addition, acknowledging the language in D.93-09-078 concerning pending regulatory changes, the Commission left open the possibility of conducting an earlier review. The Commission specifically authorized interested parties to request an earlier review through petitions to modify, under the following circumstances: [22]

(1) After the effective date of D.94-10-059 the Commission issues a final decision that establishes guidelines or proceeds with implementation steps to fundamentally change the industry structure or regulatory framework and

(2) these changes fundamentally alter the role of utilities in DSM markets or the regulatory disincentives to DSM.

As described below, the Commission issued a final decision in its electric restructuring proceeding at the end of 1995. No parties responded by requesting an

[21] The lower end of this range reflects the estimate of the total resource net benefits (resource benefits less total resource costs or "TRC") of the program. The cost-effectiveness guarantee under the shared-savings mechanism is based on this metric. The higher end of the range reflects an estimate of the performance earnings basis (or "PEB") achieved by the program, which is the metric used for calculating earnings under the shared-savings mechanism (once threshold performance is achieved and assuming that the program is cost-effective). The PEB calculates net benefits by subtracting a weighted average of "total resource" and "utility" costs from total resource benefits, in order to give weight to both perspectives and encourage the utility to minimize program costs. This calculation yields net benefits that are typically somewhat lower than net benefits from the utility cost perspective alone, and somewhat higher than net benefits from the total resource cost perspective alone. For a discussion of these metrics, see D.94-10-059, 57 CPUC 2d 1, at 38-39.

[22] D.94-10-059, 57 CPUC 2d 1, at 75.

earlier timetable for the Commission's reassessment of the shared-savings mechanism. However, in early September 1996, the Commission itself solicited comment on the timing and relevance of the 1997 review, in light of the changes to DSM brought about with restructuring. (See below.)

E. Electric Restructuring, Energy Efficiency and Shareholder Incentives

By D.95-12-063, as modified by D.96-01-009, the Commission described its vision of a competitive framework for the electric services industry. Briefly, the decision describes a future in which customers would have choice among competing generation providers, and where traditional cost-of-service regulation would be replaced by performance-based regulation. In terms of market structure, the decision placed control over all transmission assets in the hands of an independent system operator and required the utilities to bid all their generation assets (with the exception of must-take power) into a spot market pool over a five-year transition period, beginning January 1, 1998. During this transition period, some utility generating assets would undergo a market valuation process and possibly a transfer of ownership, while others would remain under the ownership of the utility and Commission regulation. The Commission would continue to have oversight over utility generation during the transition. The utilities would be given the opportunity to recover generation "transition costs" (i.e., the net above-market costs for each utility) over the 5-year period, but the price for electricity, on a kWh basis, could not rise above the rate levels in effect as of January 1, 1996.

The vision articulated in D.95-12-063 acknowledged the continued need for energy efficiency programs, but signaled a major shift in emphasis away from financial incentives to individual customers towards energy efficiency programs with broader market transformation effects, such as educational programs and incentives targeted to equipment and appliance manufacturers. The Commission envisioned a two-track approach to energy efficiency. Market transformation activities, such as increasing building or appliance standards or educating customers about their energy use, comprised one track. The Commission anticipated that market transformation activities would continued to be funded by ratepayers since they served the broader public interest, but were unlikely to be provided without ratepayer funding in a competitive market. The second track consisted of other services that customers desired, such as assistance with managing energy use at a plant or commercial site. The Commission envisioned that a competitive market would develop to provide these customer service investments, beyond some transition period.

In light of this shift to market transformation, the Commission anticipated that public funding for energy efficiency would be needed "only for specified and limited periods of time, to cause the market to be transformed." [23] Moreover, the Commission stated its expectation that the administration of energy efficiency programs would transition from the utilities to an independent, nonprofit organization:

> "After a short transition period, we believe that the funds collected through a surcharge for energy efficiency should be competitively allocated by an independent, nonprofit organization, but we would like to capture the expertise and knowledge that the utilities have gained in administering DSM programs as we begin the transition. We expect to reach closure on this issue through the implementation activities we will undertake in the next few months and through ongoing coordination with the Legislature." [24]

On September 23, 1996, Assembly Bill (AB) 1890 was signed into law. (Stats 1996, Chapter 854.) Overall, AB 1890 endorsed the Commission's vision for a restructured electric industry. With respect to energy efficiency, the statute authorized the continuation of public purpose programs through the imposition of a nonbypassable charge on local distribution service. However, in terms of funding levels for energy efficiency, AB 1890 mandated only a limited time period, commencing January 1, 1998 through December 31, 2001, during which ratepayer funds were earmarked for those

[23] *Id.* For a description of the two-track approach adopted by the Commission, see also: Working Group Report: Options For Commission Consideration, February 22, 1995, pp. 19-20; *Proposed Policy Decision Adopting a Preferred Industry Structure*, pp. 73-75, and *Customer Choice Through Direct Access*, pp. 112-113, issued by the Commission on May 24, 1994.

[24] *Id.*

activities. The statute language did not articulate any specific expectations regarding program design or administration. Those details were left to the Commission.[25]

At the Commission's direction, Working Groups met during 1996 to discuss public purpose programs, including energy efficiency, and to present recommendations responding to the issues identified in the restructuring decision. On August 16, 1996, the Energy Services Working Group (Working Group) presented a report entitled "Funding and Administering Public Interest Energy Efficiency Programs"[26]. The Working Group report presented consensus and non-consensus views on market transformation goals, the types of energy efficiency activities to be funded by utilities in the future and program funding levels. It presented administrative options for setting policies, administering the public goods charge and delivering energy efficiency activities and programs. In particular, the Working Group could not reach consensus on what future role utilities should play in administering or managing energy efficiency programs in a restructured environment.

The Commission solicited comments from all interested parties on the Working Group report, especially in light of the provisions of AB 1890. In particular, the Commission specifically asked parties to address "whether the Commission should continue with its plans to re-evaluate measurement protocols and shareholder incentive mechanisms in 1997 or defer that evaluation to the administrator of energy efficiency funds." [27] Based on the comments, the Commission determined that it would not be productive to reassess the issue of shareholder incentives under a restructured electric

[25] In passing AB995 (Stats 2000, ch. 1051), the Legislature subsequently extended energy efficiency funding for the electric utilities until January 1, 2011, and at the same time established an annual funding limit of $228 million for PG&E, SCE and SDG&E, combined. See Public Utilities Code § 399.8 (d)(1) and § 381(c)(1).

[26] Over 30 organizations were represented in the Working Group, including the utilities, energy service providers, State agencies (e.g., California Energy Commission and Department of General Services), ratepayer advocates (e.g., DRA and TURN), and environmental organizations.

[27] Joint Assigned Commissioners' Ruling in R.94-04-031/I.94-04-032, dated September 4, 1996, p. 3.

industry until the fundamental issues of administrative oversight and governing policies were resolved. [28]

Accordingly, the Commission tackled these issues in the restructuring proceeding (R.94-04-031/I.94-04-032) and addressed them in D.97-02-014, issued on February 14, 1997. In that decision, the Commission stated its intent to establish an administrative structure that would "facilitate the privatization" of energy efficiency services in the marketplace.[29] For this purpose, the Commission established an independent board (California Board For Energy Efficiency or "CBEE") consisting of regulatory representatives and members of the public to oversee limited term contracts for the administration of market transformation programs. [30] Among other things, CBEE was directed to develop and issue a request for proposal (RFP) articulating policy and programmatic guidelines for one or more administrators, subject to Commission approval. The Commission stated its goal of having the new administrative structure for energy efficiency programs in place by January 1, 1998.

The language of D.97-02-014 is instructive concerning the Commission's view at that time of energy efficiency program goals, program administration, shareholder incentives and the Commission's future regulatory role. We repeat that discussion in Appendix 2. In sum, the Commission found that the new AB 1890 regulatory structure created greater disincentives than in the past for utility development of energy efficiency in the market. In response to arguments that these disincentives could be addressed through shareholder incentives and other means, the Commission expressed its view that a utility administrative structure dependent upon shareholder incentives would be incompatible with the goal of transforming the market. Accordingly, the Commission did not adopt an administrative structure that automatically continued a utility monopoly over

[28] See D.96-12-079, 70 CPUC 2d, 254 at 277-278.

[29] D.97-02-014 in R.94-04-031/I.94-04-032 (Electric Restructuring Proceeding), 70 CPUC 2d, 774 at 784.

[30] The Commission also established a Low-Income Governing Board at that time to make recommendations about low-income assistance programs in the restructured electric industry. Since we are focusing on non low-income energy efficiency in this attachment, we do not describe developments related to the low-income board any further.

energy efficiency services, as some parties urged. However, the Commission did not preclude utilities from competitively bidding for administrative functions under the Board's RFP, although it made clear that shareholder incentives would not be authorized for any winning utility bidder. (See Appendix 2.)

During the transition to the new administrative structure for energy efficiency (i.e., until January 1, 1998), the Commission authorized the utilities to continue to administer the programs. Consistent with its findings concerning utility disincentives, the Commission further directed that "[d]uring this transition, the existing shareholder incentive mechanisms should continue to apply to utility DSM programs." [31]

E. Independent Administration and Milestone-Based Incentives

To implement D.97-02-014, the Commission first addressed several issues related to CBEE start-up, including board appointments, legal structure, authorization to contract and hire staff, conflict of interest, per diem and expense reimbursements, Bagley-Keene Open Meeting Act, among others. In recognition that the transfer of functions, funding, assets and program commitments from utilities to the new administrator would take longer than expected, in D.97-09-117 the Commission extended interim utility administration to October 1, 1998.

One of CBEE's first tasks was to develop options and recommendations for directing utility energy efficiency activities during the transition to independent program administration. In D. 97-09-117, the Commission considered CBEE's recommendations, which were submitted in the form of a Transition Report. Among other things, CBEE recommended that the utilities be encouraged to propose modifications to the current incentive mechanisms, as they redesign their 1998 programs. The Commission directed that such proposals, along with all other program planning issues during the transition, be developed through a joint planning process by the utilities and CBEE, with substantial public input.

During the joint planning process, CBEE developed recommendations for modifying current shareholder incentives, so that they would now include milestones that

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[31] *Ibid*. at 813.

relate to program management achievements, program activities or changes in markets due to the program. Management-based milestones included deadlines for implementing the program or completing training sessions. Program Activity-based milestones included the number of designers trained and the number of energy efficiency measures installed. Market Changes and Market-Effects-based milestones were based on observable changes in stocking or availability of energy efficient measures and equipment, or on demonstrable changes in awareness or knowledge.

For those programs subject to shared-savings, such as direct rebate programs, CBEE and the utilities proposed shareholder mechanisms that substantially reduced the 30% shared-savings percentage. At the same time, CBEE and the utilities proposed to 1) reduce the savings measurement period, 2) reduce the number of payment installments and 3) base earnings on *ex ante* savings estimates developed from previous year *ex post* studies.

In addition, CBEE proposed an overall cap on each interim administrator's earnings as follows: PG&E--$9.221 million; SDG&E--$3,199 million; SCE--$6.632 million and SoCal--$1.558 million. These caps were expressed as a percentage of the nine-month program budgets, and reflected CBEE's assessment of differences in the overall balance between risk and reward among programs, and among utilities.

By D.97-12-103, the Commission adopted CBEE's proposal, based on the following considerations:

> "In D.97-09-117, we recognized that the current utility incentive mechanisms, particularly shared-savings mechanisms, might not be compatible with the types of market transformation programs we wanted the utilities to initiate during the extended transition to new administrators. We therefore offered the parties the opportunity to develop modifications to these mechanisms in a consensus-building fashion. [.] In viewing the resulting proposals, we take the perspective that these modifications should offer improvements to the status quo in terms of compatibility with market transformation activities.
>
> "CBEE's proposed modifications to existing shareholder incentives meet these objectives. They clearly move in the right direction by reducing emphasis on resource savings and introduce performance milestones based on criteria more suited to market transformation objectives.

> "We have reviewed the remaining areas of disagreement, and conclude that, for the interim period, CBEE's recommendations represent a reasonable balancing of considerations related to incentive design. In particular, the Marketplace Coalition takes the position that 1) the proposed shareholder incentive amounts are excessive 2) the pay out provisions are too front-loaded and 3) the measurement requirements are insufficient. We note that the proposed shareholder incentive mechanisms reduce the current shared-savings rates substantially and also cap incentive levels, in contrast to the current uncapped 30% share rate. As an interim incentive mechanism, applying only to the next nine months of utility administration, the reduction in measurement studies and payment installments represents a reasonable quid pro quo for the sizable reduction in potential awards. As we discussed in D.97-02-014, the utilities still have significant disincentives to promoting energy efficiency in the new competitive environment that shareholder incentives are designed to offset. [.] This disincentive also applies on the gas side, since the natural gas industry has been competitive for several years. Changing the utilities earnings potential at this juncture without modifying other aspects of the incentive mechanism would, in our view, create an unacceptable imbalance in risks and rewards.
>
> "We have also considered SoCal's objection to the earnings cap imposed by CBEE. We concur with CBEE's judgment on the level of potential earnings for SoCal, given the overall balance of risks and rewards proposed by SoCal in its application….
>
> "We emphasize that these shareholder incentive mechanisms are interim in nature. Our approval of these mechanisms does not represent our endorsement of them as the basis for performance standards under the new administrative structure. As we discussed above, shareholder incentives are developed to address very specific disincentives to energy efficiency experienced by regulated utilities. In D.97-02-014, we stated that no shareholder incentives would be associated with contracts between the new administrator and the Board." [32]

The Commission then proceeded to adopt a 1998 operating budget for CBEE, establish policy rules for independent administration and approve an RFP for that administration.[33] However, beginning in early 1998, the transition to independent

[32] D.97-12-103, 78 CPUC 2d, 1 at 18-19.

[33] See D.98-02-040 (78 CPUC 2d, 439) and D.98-04-063 (79 CPUC 2d, 704).

administration for energy efficiency programs encountered several obstacles—and was ultimately put on hold indefinitely by the Commission. We summarize the sequence of events in the following paragraphs.

On February 4, 1998, in response to a complaint by the California State Employees Associations, the State Personnel Board's (SPB) Executive Director issued a disapproving the agreements between CBEE and its administrative and technical consultants. A related complaint by the Association of California State Attorneys and Administrative Law Judges regarding agreements between CBEE and legal consultant services was also pending at the SPB. As a consequence, CBEE no longer had the resources to perform the work needed to meet the Commission's deadlines. By ruling dated February 24, 1998, the Assigned Commissioner called for Board and public comment on next steps for energy efficiency activities in the event that the current structure could not continue in substantial part. Reluctantly, in response to comments and the existing circumstances, the Commission extended the period of interim utility administration of energy efficiency until December 31, 1998.[34]

During the summer, 1998, the Commission entered into settlement agreements with the California State Employees Association (CSEA) and the Professional Engineers in California Government, which resolved the dispute regarding the provision of administrative and technical support for CBEE and the Low-Income Governing Board. Under these agreements, the Commission agreed to take all reasonable steps to create and fill a combined total of nine civil service positions and to transfer any civil service duties and responsibilities previously performed by the administrative and technical consultants for CBEE to these positions. Pursuant to the agreement with CSEA, and subject to certain conditions, once the civil service positions were filled, the Commission or Boards could contract for the services of up to eight full-time equivalent consultants to perform work for the Boards. The agreements recognized that there would be a transition period until the new civil service positions could be established. Therefore, the Boards were

[34] D.98-05-018 (80 CPUC 2d, 218).

authorized to resume the services of the administrative and technical consultants through the transition period.

In view of these developments, the Commission concluded that it was feasible to move forward with independent administration, and authorized Energy Division to issue the RFP in D.98-07-036. However, after the issuance of D.98-07-036, two additional obstacles surfaced during the final days of the California legislative session.

First, the Governor vetoed the Commission's budget request for additional positions necessary to fulfill the terms of the settlement agreements described above. Second, the Governor vetoed AB 2461. This bill, among other things, would have provided that fund administration for energy efficiency and low-income programs be handled by the State, with the program funds to be transferred to the State Treasury. The bill also provided for independent program administrators, with an operative date starting July 1, 1999.

Recognizing that these actions created insurmountable obstacles to handing off energy efficiency programs to new administrators as planned, coupled with the desire to reduce uncertainty and service disruption in the market, the Commission extended interim utility administration through December 31, 2001, and cancelled the RFP authorized by D.98-07-036.[35] On June 10, 1999, the Assigned Commissioner suspended further exploration of administrative options until further notice, in response to legislative proposals to transfer responsibility of energy efficiency programs after 2001 to the California Energy Commission. [36]

In the meantime, to reduce the potential conflicts between the utilities' role in the newly competitive energy services industry and their continued role as interim program administrators, the Commission directed them to transfer implementation activities away from themselves and towards other market participants. With respect to shareholder incentives, the Commission continued to refine the milestones and overall funding caps

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[35] D.99-03-056.

[36] D.00-02-045, mimeo. p. 6. On October 6, 1999, the Governor signed AB 1393 into law. Among other things, that law required that low-income programs continue to be administered by the utilities.

in subsequent decisions for PY1999, 2000 and 2001. By D.01-11-066, however, the Commission discontinued shareholder incentives for energy efficiency programs altogether:

> "In the past, the Commission has offered shareholder incentives to large [investor-owned utilities] for successful program delivery, in lieu of a profit margin. The Commission will no longer make a special provision for shareholder earnings. Both utility and non-utility entities are free to propose program budgets they feel are necessary for their organizations to complete the program delivery successfully." [37]

Thus, with the 2002 program year, all incentive payments for energy efficiency programs have ceased.

[37] D.01-11-066, Attachment 1: *Energy Efficiency Policy Manual*, p. 28. See also D.02-03-056, mimeo. p. 54.